SPE 37334

Application of Reservoir Management Techniques to the East Randolph Field, Portage County Ohio: Reservoir Engineering Study

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This paper was prepared for presentation at the 1996 SPE Eastern Regional Meeting held in Columbus, Ohio, 23–25 October 1996.

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Abstract

Exploration in the Cambrian Rose Run Formation in Ohio resulted in the 1992 discovery of a prolific oil reservoir, the East Randolph field. In the last two and a half years the reservoir produced 450,000 STB and 1,200,000 MCF, and the average reservoir pressure declined from 3,100 psi to 2,200 psi.

Declining reservoir pressure, high producing GORs, and operational problems dictated the need for developing a comprehensive reservoir management strategy to improve the operational economics and optimize the oil recovery in the field. Under the Department of Energy Reservoir Management Demonstration Program, a team composed of professionals from Belden & Blake and BDM-Oklahoma was organized to study the potential for improving recovery through infill drilling, waterflooding, and gas repressurization.

Further development drilling has confirmed new reservoir limits, and volumetric and material balance analyses indicated potential OOIP exceeding 10 million barrels (compared to the original estimate of 4.4 million barrels). Based on core and log data, a three-layer geologic model was developed to describe the reservoir with the top layer primarily a gas producing zone and the bottom two layers as oil producing zones. Pressure buildup tests, PVT samples, and core relative permeability data were utilized to understand the fluid behavior and develop the reservoir model.

The developed geologic model and the collected and analyzed data were used as the basis for a numerical reservoir simulation study to history match the production and pressure performance, and to predict the effect of different oil recovery techniques. A phased approach was utilized to simulate the study area by first performing a single well simulation to determine the sensitivity of the simulation results to various reservoir parameters. Results of the single well simulation and the developed geologic model were then used to model the performance of the full field. The field was simulated to examine the potential for infill drilling and an infill well was drilled and cored. The impact of waterflooding and gas repressurization were also evaluated.

Program Objectives

BDM-Oklahoma, on behalf of DOE, solicited brief proposals to perform cooperative or cost shared research in developing and implementing reservoir management plans in pursuit of its goal of improving reservoir management understanding through demonstration and technology transfer[1]. Three development projects submitted by small operators of oil reservoirs were selected on the basis of the regional significance of the projects, their potential for economic success, the demonstrated degree of problem identification, the availability and quality of data for addressing the key problem(s), the suggested approaches for solution, and the teaming arrangements suggested by the operators.

Once a project is selected, a multidisciplinary team develops a detailed joint work statement delineating the scope of the project, its individual subtasks, the schedule of proposed activities, the need for additional data collection, and the goals and responsibilities of team members. Regular meetings of teams and subteams make optimization of the ongoing work possible through modifications of work plans. Teams are composed of experienced engineers, geoscientists, and other professionals representing BDM-Oklahoma, local operators, service companies, research organizations, state surveys, etc.

This paper will focus on one of three reservoir management projects now underway in this DOE-sponsored program, a project being conducted by BDM-Oklahoma with Belden and Blake Corporation in the East Randolph field. The discussion will cover the field history, geologic and production analyses leading to a detailed reservoir engineering study.

Field History

Since 1992, Belden and Blake Corporation and PEP Drilling Company have developed this unique but significant oil reservoir in the Cambrian Rose Run formation in Randolph Township, Portage County, Ohio (Figure 1). This new field, one of a few to produce oil from the Rose Run, covers about 3,400 acres. The Rose Run lies at a depth of about 7,200 ft, and contains an average of about 15 ft of net pay in the upper three of five sand zones typically present in the Rose Run (Figure 2). The field contains 32 wells and has produced about 450,000 bbl of 42^{o} API oil and more than 1.2 billion cubic ft of gas as of June 1996. Development wells continue to be drilled as the reservoir management project proceeds.

Problems being addressed in this study include evaluation of location for potential development and infill wells, optimum selection (waterflood or gas injection) and implementation of secondary recovery approach, alleviation of paraffin buildup in producing wells, and optimization of hydraulic fracture stimulation techniques. The general nature of these problems was identified by the operator prior to the inception of the project.

Geologic Interpretation

Data on the East Randolph field were received from Belden & Blake and PEP Drilling, each operators of multiple wells in the field. These data were integrated into a geologic interpretation of the Rose Run sandstone for the East Randolph field. Well log and core analyses were conducted to determine the reservoir distribution, the heterogeneity of the hydrocarbon producing intervals, and the effects of faulting and fracturing on well productivity.

The Rose Run sandstone is a member of the Upper Cambrian Knox Supergroup. The Rose Run sandstone ranges in thickness from 130 to 150 ft and consists of stacked sheet sand deposits separated by and interbedded with thin, low permeability dolomites and carbonaceous shales. The Rose Run sandstone is overlain by the Beekmantown Dolomite, which is capped by the Knox unconformity, and underlain by the Trempaleau Dolomite. Hydrocarbon traps in the East Randolph field are a combination of structural and stratigraphic features.

Structural Features: Eight East-West (E-W) and 1 North-South (N-S) structural cross sections were constructed for identification and interpretation of faulting and associated fracturing. Two stratigraphic cross sections were constructed for identification and correlation of individual flow units and permeability barriers. The Rose Run sandstone in the East Randolph field strikes along a southwest to northeast trend and dips 1 to 2 degrees to the south and east, as shown in Figure 3[2]. Faults were identified by the changes in dip and thinning of interval thickness. Fracture systems may be associated with the faulting and affect fluid migration. The displacement may be enough so that the faults juxtapose tight dolomites against the permeable sandstones causing permeability barriers or discontinuities. The effect of the barriers will be investigated by comparison of production, gas-oil ratios, and water-oil ratios across the fault zones.

Stratigraphic Features: The productive Rose Run sandstone in the East Randolph field can be divided into three distinct sand members characterized by bedding, mineralogy, and log character. The geologic data from well log interpretation were input into geologic modeling software for the construction and interpretation of structure, net pay, production, gas- and water-oil ratios, and production maps[3]. Net sand thickness maps use a 6% porosity cutoff based on core plug porosity-permeability crossplot interpretation. These maps were continuously revised with additional data collected during the project.

The uppermost sand member (Zone 1) is laterally discontinuous and generally non-productive in the East Randolph field. The sand ranges up to 2 ft in thickness with low porosity and permeability. Based on gas detection while drilling on air, which usually does not exceed 100 units, this zone contributes only small volumes of gas to total production in the East Randolph field. To the west of the East Randolph field, this sandstone becomes thicker and more porous, and is one of the productive intervals in the West Randolph gas field. Because of the poor reservoir quality of this zone, no maps were constructed.

The Rose Run sandstone Zone 2 is generally continuous across the area and ranges from 1 to 8 ft thick. The sand trends to the NE-SW with an average net sand thickness of approximately 5 ft using a 6% porosity cutoff, as shown in Figure 4. Porosity pinches out rapidly to the west. The sandstone has a sharp lower contact with interbedded dolomite.

The Rose Run sandstone Zone 3A is more continuous across the area and ranges from 2 to 12 ft in thickness. The sand trends to the NE-SW with average net sand thickness of approximately 7.5 ft (See Figure 5) using a 6% porosity cutoff. The sandstone has a sharp lower contact with thin shales separating the dolomites from the overlying sandstones. The porosity is highest in those wells with the largest net sand thickness. The interbedded dolomites act as baffles to fluid flow and create fluid-flow compartments.

Rose Run sandstone Zone 3B typically consists of two separate sandstone deposits separated by a thin dolomite interbed. The sandstones that comprise this zone trend to the NE-SW. Individual sandstone deposits are continuous locally, but discontinuous regionally. Thickness ranges from 3 ft up to 12 ft with average net sand thickness using a 6% porosity cutoff of approximately 8 ft, as shown in Figure 6. The porosity of this zone pinches out rapidly to the east and west, but is continuous to the north. Several wells along the southeast margin of the field were not completed in this zone due to the zone's high water saturation.

Production Analyses

Since its discovery in 1992, the East Randolph field has produced over 450,000 barrels of oil and 1.2 billion cubic ft (bcf) of gas from the Rose Run sandstone from 32 active wells. Cumulative production maps are biased due to the range in production times for the wells from only a few months to several years. Therefore, production, gas-oil ratio, and water-oil ratio maps were made for each well's first 6, 9, and 12 months of production to normalize the data and to account for the range in well completion dates and production data over the last couple of years. The highest oil production rates and cumulative oil production volumes per period correlate with the thickest net sands in the central part of the field, as shown in Figure 7. These sands also have the highest porosity and permeability, and lower water saturation. Wells in the southern and eastern portion of the field have lower cumulative oil production per period due to slightly lower porosity, higher water saturation in zone 3B, and possibly completion differences. Several downdip wells along the eastern boundary of the field have not been completed in Zone 3B due to the high water saturation.

Gas production volumes correlate best with the highest net sand thickness and reservoir quality of Zone 2, as shown in Figure 8. High initial gas-oil ratios (GOR) suggest an initial gas cap may have been present where Zone 2 is best developed in the updip portion of the field, as shown in Figure 9. The high gas production rates of recent extension wells in the northern part of the field suggest separate reservoir compartments under different reservoir conditions are present due to faulting or permeability barriers. The high gas saturation of Zone 2 has been observed when drilling on air through the zone and from log analyses.

Core And Log Analyses And Interpretation

Core description and special core analyses were performed by BDM-Oklahoma on the Rose Run sandstone core from the McGuire #2 infill well which was spudded on June 15, 1996. Objectives were to determine lithologies, heterogeneities, permeability barriers, reservoir quality, and relationships to production. Belden and Blake solicited a third party laboratory to perform the routine core analyses on the core.

Core analyses by BDM-Oklahoma indicated that Zone 2 sandstones are light gray to medium gray, fine-grained, well sorted, and parallel laminated to cross-laminated. The sandstone lithology is classified as arkosic. Core porosity measurements for Zone 2 range from 1.7% to 6.2%; air permeability ranges from 0.01 to 0.42 mD. Log porosity varies from 1 to 7%, with neutron-density crossover of 4 to 6% suggesting high gas saturation.

Zone 3A is a light gray to medium gray, well sorted arkosic sandstone. The sandstone is parallel laminated to lenticular cross laminated. Porosity for Zone 3A ranges from 7.3% to 11.1%. Air permeability ranges from 1.02 mD to 12.9 mD; brine permeability ranges from 0.42 mD to 1.92 mD, approximately 10% of air permeability. Water saturation ranges from 32.5% to 51.4%.

Zone 3B is a tightly cemented, light gray to medium gray, parallel laminated to ripple cross laminated, well sorted, arkosic sandstone. The sandstone is burrowed near the top. Zone 3B porosity ranges from 7.9% to 10.6%. Air permeability ranges from 0.54 mD to 2.13 mD; brine permeability ranges from 0.14 mD to 0.38 mD, approximately 10% of air permeability. Water saturation ranges from 49.2% to 70.7% indicating a higher water saturation toward the base of the Rose Run interval.

Furthermore, results from the CMR (Combinable Magnetic Resonance) log indicated a varying irreducible water saturation among the three zones. Zones 3A and 3B measured an irreducible water saturation of 41% and 33% respectively, whereas Zone 2 indicated an irreducible water saturation of 25%. Log interpretations for the McGuire #2 core well indicated initial water saturations for zones 2, 3A, and 3B at 26%, 34%, and 41%, respectively. It is worthy to mention that the relative permeability measurements for Zone 3A indicated an irreducible water saturation of 32%.

Reservoir Engineering Data Collection And Analyses

Early in the project, a single-well reservoir model (D'Agostine well) was developed to run on BOAST3-PC[4] for the purposes of assessing whether reasonable reservoir parameters could be estimated from the minimal field data. BOAST3-PC, a modified version of BOAST II, is a three-phase three dimensional Black Oil simulator developed by Louisiana State University under contract from the U.S. Department of Energy.

Initial reservoir parameters were analyzed to estimate PVT data based on various published PVT correlations. The relative permeability and capillary pressure performance for the field were not available, and therefore were predicted using existing data from analogous Marlboro (located a few miles to the South) and West Randolph fields. Well stimulation data for the Belden & Blake wells were evaluated, and fracture gradients for the wells were computed. The resulting single-well model was found to be unstable due to the high initial gas/oil ratio (GOR). This well has the highest GOR in the field, which can be attributed to either initial conditions below the bubble point with an initial gas cap or conditions above the bubble point with the top zone being gas and the other two oil saturated.

In an effort to better define the PVT parameters, BDM-Oklahoma attempted to use a commercially available PVT correlation model to predict PVT data based on initial reservoir fluid conditions. It was determined that additional detailed reservoir data were needed to project the reservoir fluids behavior using this model. The PVT correlations in the literature were revisited, and several model data sets were developed for use in the modeling, but it was concluded that actual field PVT data were required in order to reasonably simulate the field performance. In addition, it was determined that the pressure data, relative permeability data, and material balance calculations for the field were needed to accurately simulate field performance. Since at the time, the field was still in the development stage, it became important to re-examine the material balance calculations and volumetric analyses in order to estimate and update the original oil-in-place (OOIP) value for the field. A list of the initial reservoir data is exhibited in Table 1. Initial reservoir data for the East Randolph field were estimated from available log interpretations, collected pressure data, and fluid samples.

Pressure Build-up Analysis: The lack of reservoir engineering data needed for material balance calculations, and simulation study required the need to measure the reservoir pressure at different times during the life of the field and estimate the various reservoir properties. A 14-day pressure build-up test was conducted on the McGuire # 1 well located south of the new core well (McGuire #2). Collected data from the test were analyzed by BDM-Oklahoma and Belden & Blake. BDM-Oklahoma used a commercially available pressure transient analysis software model for analyzing the pressure data. The Horner technique and automatic type curve matching were used to predict the effective reservoir permeability, formation damage, and estimate reservoir pressure. Figures 10 and 11 exhibit Horner plot and type curve matching of pressure and pressure derivative data respectively. In addition, the results from applying both techniques are summarized in Table 2.

PVT Data Analysis: The lack of pressure data and the need to understand the fluid behavior in terms of fluid properties, bubble point pressure, and solution gas-oil ratio, dictated the need to run PVT analysis on fluid samples from East Randolph field. In November 1995, a surface-recombined sample from McGuire #1 was collected by Belden & Blake for analysis. As indicated earlier, the single well simulation study revealed the need for PVT data representative of the fluid from the field. In addition, available data were not sufficient to apply PVT correlations to predict the fluid phase behavior.

The following set of analyses were performed:

- Separator gas composition analysis
- Adjusted reservoir fluid composition
- Pressure-volume relations
- Viscosity of reservoir fluid
- Separator flash analysis

At the time the sample was collected, the average reservoir pressure was estimated at 2,065 psig with the average reservoir temperature reported at 130˚F. Table 3 is a summary of the results of performing PVT analyses of the surface-recombined sample.

Relative Permeability and Capillary Pressure Data Collection: Initially and due to the lack of relative permeability and capillary pressure data from the East Randolph field, the reservoir management project team reviewed available data from analogous reservoirs to generate a set of relative permeability and capillary pressure data to best describe the fluid behavior for wells producing from the East Randolph field. Available gas-water relative permeability data from the Ward No. 1 well in West Randolph gas field were evaluated and used as a starting point to describe the gas-water relative permeability relationship for Zone 2, which is believed to be primarily a gas zone.

In order to describe the oil-water relative permeability relationship for zones 3A and 3B, relative permeability and capillary pressure data from the Marlboro field, producing from the Clinton reservoir, were evaluated. In addition, the project team solicited the help of BDM-Oklahoma’s Reservoir Characterization Group to evaluate oil and gas relative permeability data for similar millidarcy-range permeable rocks.

The generated relative permeability and capillary pressure data from analogous reservoirs were used as a first approximation in the simulation process of the East Randolph production data. It is worthy to note that the accuracy of the simulation process is dependent on collecting the actual relative permeability and capillary pressure data from the field. From this perspective, core plugs from the McGuire # 2 were used to experimentally generate the relative permeability and capillary pressure data for the reservoir.

Steady-state imbibition and second-drainage oil-water relative permeability measurements were performed at 72˚F on a sample from Zone 3A. Fluid saturations were monitored using a linear X-ray scanner. Imbibition cycle oil and brine relative permeabilities were measured at six brine fractional flows ranging from 0.05 to 0.975. A brine permeability of 0.037 mD was measured at residual oil saturation of 0.45. Second-drainage cycle oil and brine relative permeabilities were measured at six brine fractional flows ranging from 0.975 to 0.05. A permeability to oil of 0.314 mD was measured after the second-drainage at residual brine saturation of 0.294. Steady-state imbibition oil-brine relative permeability results are exhibited in Figure 12.

Oil-brine centrifuge tests were performed on samples from zones 3A and 3B. The Hassler-Brunner[5] and Rajan[6] methods were used to interpret capillary pressures from the centrifuge data. Fluids used during the centrifuge tests were the same as those used in the oil-brine relative permeability tests. The brine saturated plugs were first centrifuged in oil to yield primary drainage capillary pressure versus saturation data. The plugs were then centrifuged in brine to obtain first imbibition cycle capillary pressure and saturation data, and finally centrifuged again in oil to yield second-drainage cycle capillary pressure and saturation data. Capillary pressure and saturation data were used to calculate areas and wettability indices. Wettability indices were close to 1 indicating that the plugs were preferentially water wet. Oil-water capillary pressure results are exhibited in Figure 13.

In addition, a waterflood susceptibility test was conducted on several plugs from the McGuire #2 well. The plugs were flooded with laboratory oil at a rate of 150 mL/hr to achieve residual brine saturation condition. The residual brine saturation, expressed as a function of pore volume, ranged from 31.5% to 44.9%. Prior to waterflooding the sample, the oil injection rate was reduced to 3 mL/hr. The waterflood was started by switching from oil to brine at 3 mL/hr yielding an injection rate of 0.53 pore volumes per hour or a linear displacement of 2 ft/day. Residual oil saturations achieved during these tests ranged from 25% to 45% yielding oil recovery rates from 30% to 58% of OOIP.

Volumetrics and Material Balance Calculations: Net sand thickness isopach maps generated with commercially available software, were used to compute the original oil-in-place (OOIP). Porosity and water saturation maps for the three layers under study were also used in the process. Volumetric calculations were performed for each layer to determine each layer’s contribution to the total OOIP. Table 4 summarizes the results of the volumetric calculations by layer.

Zones 3A and 3B have higher OOIPs than Zone 2 because Zone 2 is thinner, has lower porosity, and is believed to be primarily a gas zone. This assumption was based on production data analysis and material balance calculations.

Material balance calculations using a commercially available material balance software package, were performed using the available production and reservoir pressure data. In addition, PVT data from the McGuire #1 well were used as input for the material balance computation.

In the first step, the software predicted OOIP based on available reservoir pressure and cumulative production. In order to predict OOIP, the software required assigning a value representative of the initial gas/oil volume in the reservoir (fraction). A sensitivity on different initial gas/oil volume values was performed generating a wide range of OOIP values. For example, at initial gas/oil volume fraction of zero, the calculated OOIP was 81.6 MMSTB for the East Randolph field. At an initial gas/oil volume of 0.12 (fraction), the OOIP was calculated at 17 MMSTB, and at initial gas/oil volume of 0.20 the OOIP was calculated at 11.2 MMSTB, this correlates with the OOIP value based on volumetrics.

The next step was to implement the pressure match option where both the OOIP and gas/oil volume were known. The software has the capabilities of predicting PVT data based on correlations and initial values. The PVT option was utilized and the generated values were compared with the PVT data measured at Core Laboratories and were found to be in agreement. Two cases were simulated, the first case with OOIP at 12 MMSTB and gas/oil volume of 0.17, and the second case with an OOIP of 11.5 MMSTB and gas/oil volume of 0.15. Results of the pressure match indicated, (as illustrated in Figure 14) that case #1 with gas/oil volume of 0.17 and OOIP of 12 MMSTB exhibited the better pressure match.

Reservoir Simulation Studies

As previously indicated, a single well reservoir simulation study was performed on the D'Agostine well #1 in an attempt to match the production and pressure histories. Due to the high GORs from the D'Agostine, and the lack of PVT, pressure, and sufficient core data, the single well simulation for the D'Agostine was terminated due to the lack and inaccuracy of input data. In the mean time, the efforts of the project team concentrated on collecting additional pertinent data to assist in the simulation process and ultimately in the design of the waterflood or gas injection project.

Fluid samples were collected from the McGuire #1 and PVT analyses were performed as mentioned earlier. In addition, a 14-day pressure build-up test was conducted on the McGuire #1 and pressure-time data were analyzed to determine the various reservoir parameters necessary for the simulation process.

The McGuire #1 was selected due to data availability. As results of the pressure build-up test and PVT analyses became available, the project team initiated a single well model simulation for the McGuire #1 as part of a phased approach. Under this phased approach, the first step was to conduct the single well simulation and predictive study on the McGuire #1. The second step was to conduct a sensitivity study on the various simulation parameters using the single well model to determine if additional data are needed to improve the results of the simulation process. The third step was to perform a full-field simulation study and determine the technical and economic feasibility of implementing waterflooding and/or gas pressure maintenance as improved recovery processes.

Single Well Model Simulation-McGuire # 1: The first step in the process was to simulate the production and pressure history for the McGuire #1 using BOAST3-PC. When simulating the production for the McGuire #1 the following assumptions and input data were taken into consideration:

- McGuire #1 well produces from a drainage area of 60 acres
- Based on the developed geological model, a three layer system was assumed with the top layer primarily a gas zone and the bottom two layers being oil producing zones
- Use the laboratory derived PVT data from the McGuire #1 well to describe the fluid behavior
- Modify/generate relative permeability data based on available data from similar or nearby reservoirs
- Use implicit pressure calculations for the producing oil well by specifying well productivity index (PI), and bottom hole flowing pressure

Results of the single well history match of cumulative production for oil, gas, and water are shown in Figures 15, 16, and 17. History match results indicated that simulated production data are within 10% of the actual data.

In order to validate the presence of high gas saturation in Zone 2, the single well model was simulated with all three zones as oil producing zones with no free gas. The only gas present in the system was assumed to be solution gas. Simulation results of this case exhibited reasonably good oil and water history matches, however, the gas match was 60% less than the actual gas production. These results indicated that an initial gas saturation must be present in Zone 2 in order to arrive at an acceptable match of gas production.

After arriving at a reasonable match of historical production data, the project team developed a base case simulation run to project the primary production for the McGuire #1 to the economic limit and to compare the simulated base case recovery to decline curve projections. Decline curves generated by Belden & Blake for the McGuire #1 were used to determine the economic limit and ultimate recovery for the well. In addition, the single well simulation model was used to project the production rate for the McGuire #1 to the economic limit. Results of the base case oil and gas production rate simulation versus the decline curve extrapolations are shown in Figures 18 and 19.

A quarter of a 5-spot pattern was simulated to predict the effect of water injection on the McGuire #1. These results were compared to the base case prediction. Preliminary results of this study indicated an incremental recovery of 13,000 STBO. It is worthy to note that these results only reflect the behavior of the McGuire #1 well which has a low permeability of 1.35 mD compared to higher permeabilities in other nearby wells. It is also important to note that the single well simulation predicted a reservoir pressure of 2,000 psi, prior to the start of water injection, at the extreme edge/corner of the simulated area. This particular location is representative of the location for the McGuire #2 which was spudded in June 1996, approximately the same time as the designed start of the water injection for the McGuire #1. After completion the McGuire #2 measured a pressure of 2,200 psi.

Full-Field Simulation: The development of the input data set for the full-field simulation was initiated as more experimental and field data became available. The simulation grid represents an area of the field 20,500 ft wide by 10,700 ft long which contains 25 wells. A rotated, non-uniform, 65 by 41 grid using three layers was designed to simulate the area. Values of net pay, porosity, and water saturation were generated for each grid block representing the study area. These values were generated by electronically superimposing computer generated geological maps and the grid map representing the study area. Saturation values for the pay zones were calculated for various wells so that this data could be mapped and imported into the simulator. The differences in log response measured by the three logging companies used in the field, as well as differences in log response between wells logged by the same vendors, caused water saturation calculation problems, but the data were normalized to establish and map a consistent set of values.

Two steps were anticipated to complete the full-field simulation study. The first step, already completed, was to history match the production and pressure data from the 25 production wells in the study area. The second step will be to predict the performance of the field as a result of waterflooding and/or gas injection. This paper presents only the results of the full-field history match process.

History matching the actual production and pressure data for the field was accomplished by holding constant known field and experimental data such as fluid properties and initial oil, water, and gas saturations. In addition, experimentally determined relative permeabilities and capillary pressure values were not changed or modified. In order to simulate the field performance, two different rock regions were modeled, each having different relative permeabilities and capillary pressure values. Zone 2 was represented by one rock region depicting a three phase system with an irreducible water saturation of 25%, whereas Zones 3A and 3B were represented by a different rock region producing from a two-phase system (oil-water) with an irreducible water saturation of 32%. Figures 20, 21, and 22 show the full-field history match of cumulative oil production, cumulative gas production, and reservoir pressure, respectively. A satisfactory history match of water production was not achieved due to the nature of the experimentally determined relative permeability data for Zones 3A and 3B; however, it was decided to accept the results of the water history match and not to tamper with the experimentally determined relative permeability data in order to maintain the integrity and accuracy of predicting the performance and feasibility of waterflooding and gas injection.

Summary and Conclusions

The reservoir management project team has successfully accomplished 90% of the tasks outlined in the joint work statement. Additional work is continuing towards the completion of the project. Special core analyses were performed on samples from an infill core well. Relative permeability, capillary pressure, and water susceptibility values were measured. This information was used to enhance the geologic model and to determine the potential for oil recovery by waterflooding and/or gas injection. Material balance and volumetric analyses indicated the presence of a larger original oil-in-place of 10 million barrels of oil compared to a pre-project estimate of 4 million barrels of oil. Results of the full-field pressure history match indicted that the wells are in pressure communication, disproving the presence of different reservoir compartments.

Results from this study will be used to establish the economic feasibility for implementing waterflooding and/or gas injection. In addition, these results will assist in selecting and implementing a pilot test.

Acknowledgments

The authors and other researchers participating in the Reservoir Management Demonstration Program are appreciative of the US Department of Energy’s foresight in supporting this Reservoir Management Project. This product would not have been possible without the dedication and support received from all members of the East Randolph field reservoir management team. The authors would like to express their thanks to Dr. Mike Madden, Dr. Mike Fowler, and Viola Rawn-Schatzinger of BDM-Oklahoma for their review of the manuscript and helpful discussion. We are also grateful to BDM-Oklahoma Information Services Department for their support and editorial review.

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TABLE 1—EAST RANDOLPH FIELD DATA

Depth	7,200 ft
Porosity	5 to 10%
Water Saturation	30%
Permeability	0.5 to 2.0 mD
Gross Interval	50 ft
Net Pay Thickness	15 ft
Oil Gravity	42 °API
Initial Reservoir Pressure	3,100 psia

TABLE 2—RESULTS OF PRESSURE BUILD UP ANALYSIS-MCGUIRE #1

	Horner	ATCM	B&B
Effective Permeability, mD	1.35	1.33	1.37
Skin Factor	-2.09	NA	-2.64
Initial Pressure, psia	2,513 (P*)	3,160	2,500 (P*)

. P is false pressure, pressure extrapolated at Horner time equal to 1.

TABLE 3—SUMMARY OF PVT DATA ANALYSIS

Average Reservoir Pressure	2,065 psig
Average Reservoir Temperature	130° F
Saturation Pressure	2075 psig
Average Compressibility	8.74 E-6 volume/volume/psi
Reservoir Fluid Viscosity	0.738 cp
Formation Volume Factor	1.221 Res. BBL/STB
Total Solution GOR	485 SCF/STB
Tank Oil Gravity	42° API

TABLE 4—VOLUMETRIC ORIGINAL OIL-IN-PLACE ANALYSIS BY RESERVOIR LAYER FOR EAST RANDOLPH FIELD

Reservoir Layer	Area, acres	Volume, MBO
Rose Run 2	2,698	512
Rose Run 3A	3,477	5,020
Rose Run 3B	3,339	5,800
TOTAL		11,332

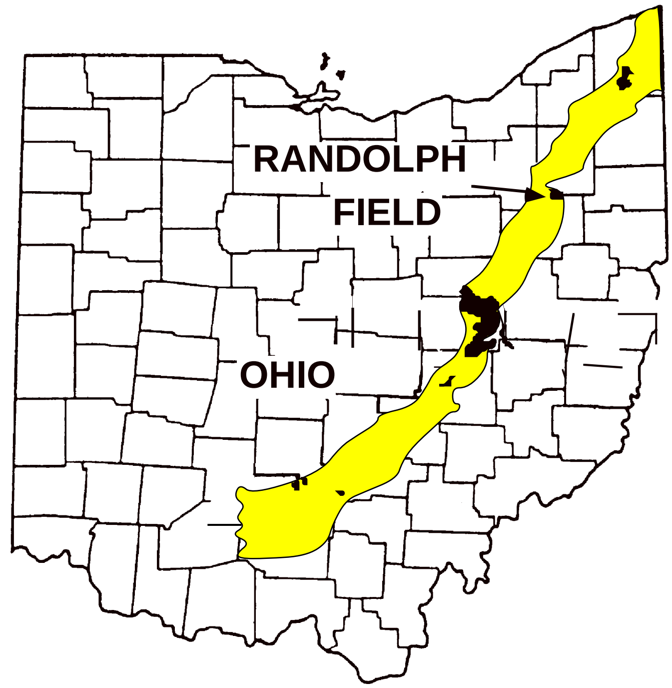

Fig. 1—The East Randolph oil field is located in eastern Ohio in a northeast-southwest rend of reservoirs producing (mostly gas) from the Rose Run and the Beekmantown.

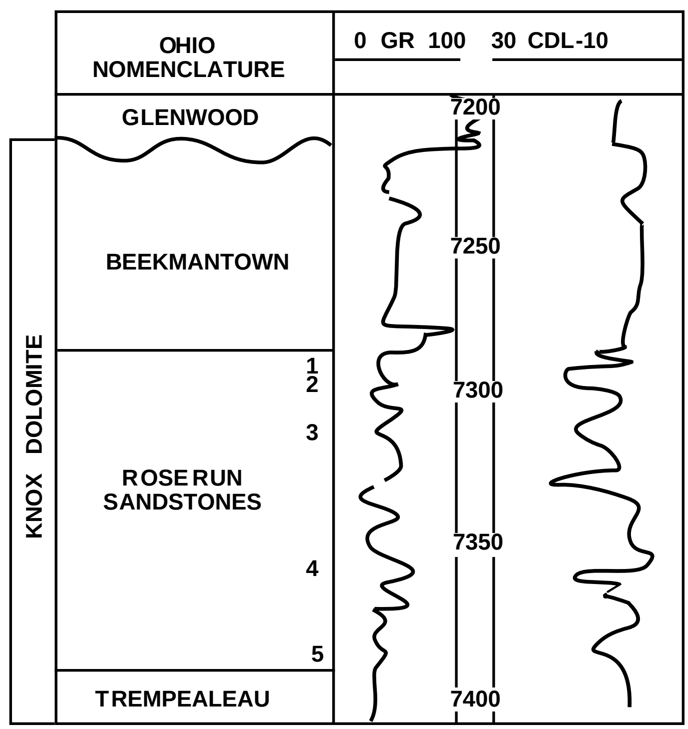

Fig. 2—Type Log for the East Randolph Field

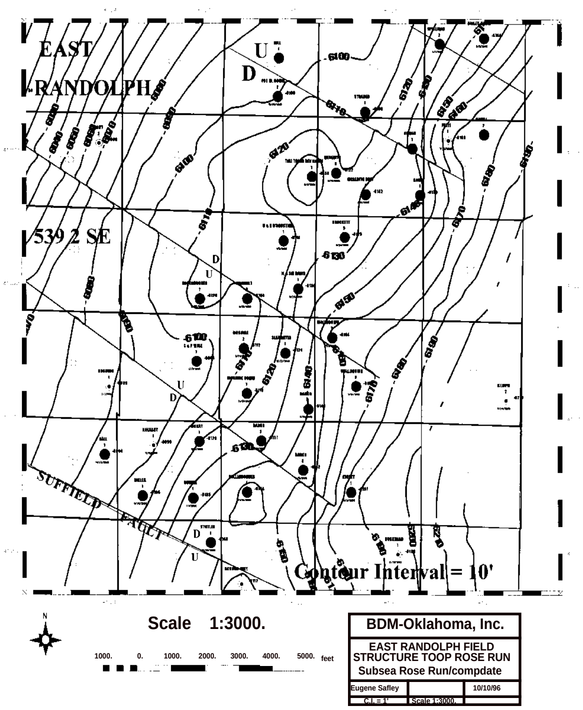

Fig. 3— Structure Top of the Rose Run

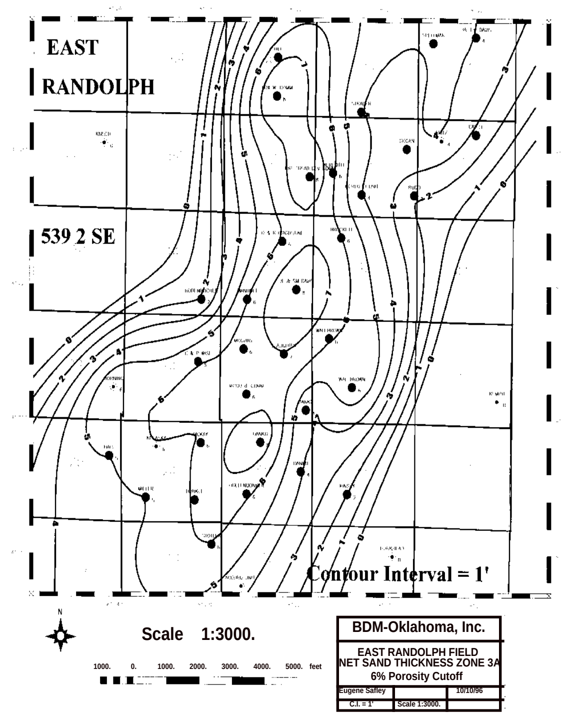

Fig. 5—Isopach Net Sand Thickness RR3A

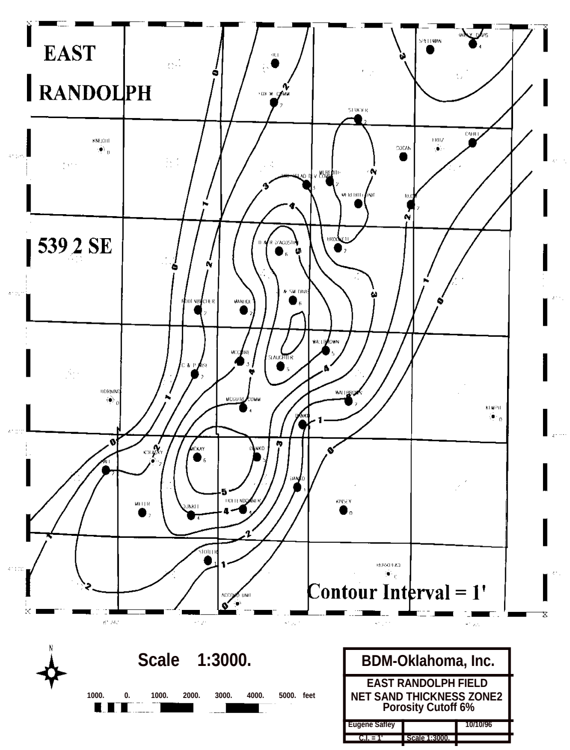

Fig. 4—Isopach Net Sand Thickness RR2

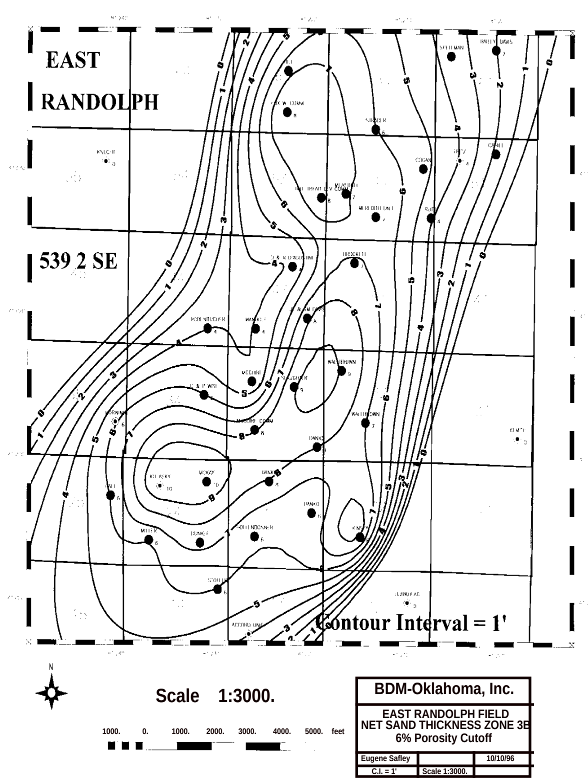

Fig. 6—Isopach Net Sand Thickness RR3B

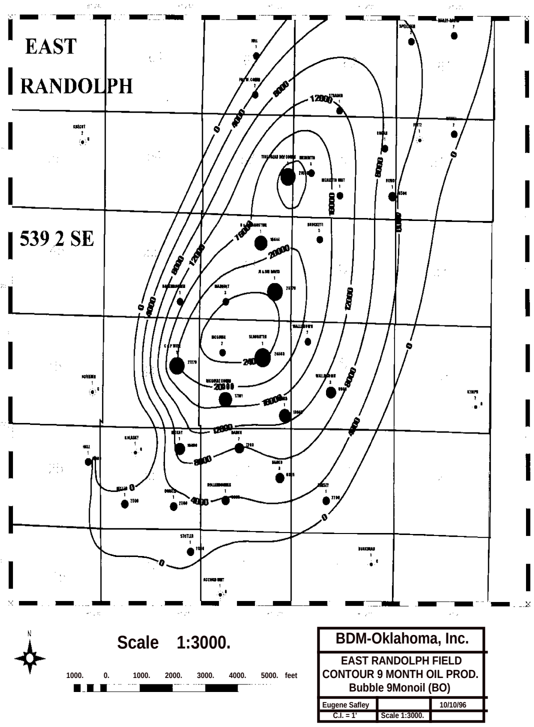

Fig. 7—Contour First 9 Month Oil Production

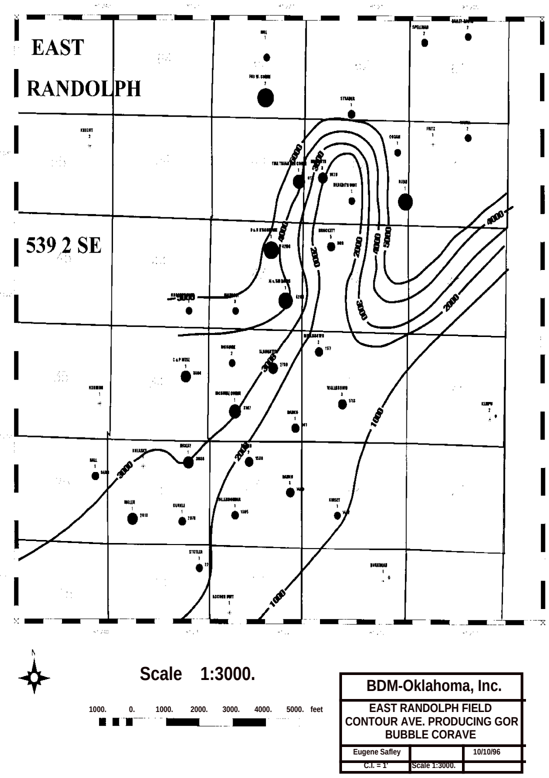

Fig. 9—Contour Average Producing GOR

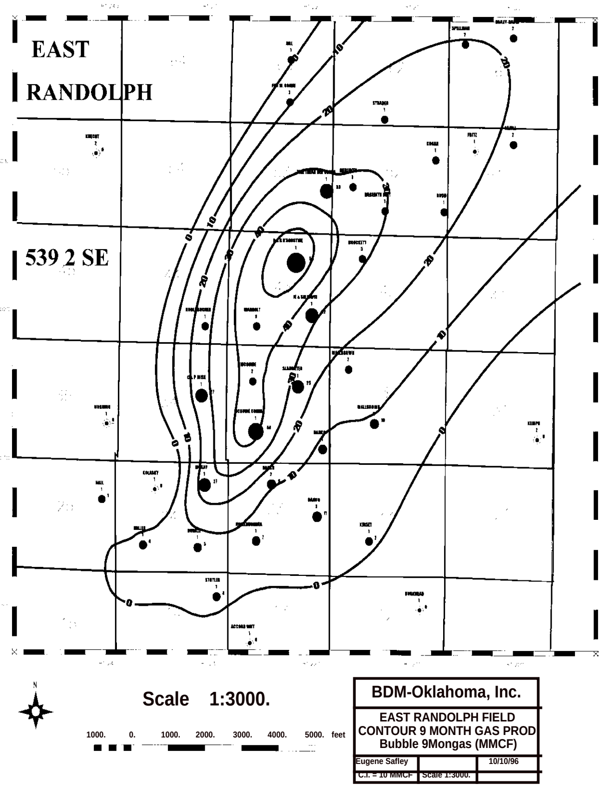

Fig. 8—Contour First 9 Month Gas Production

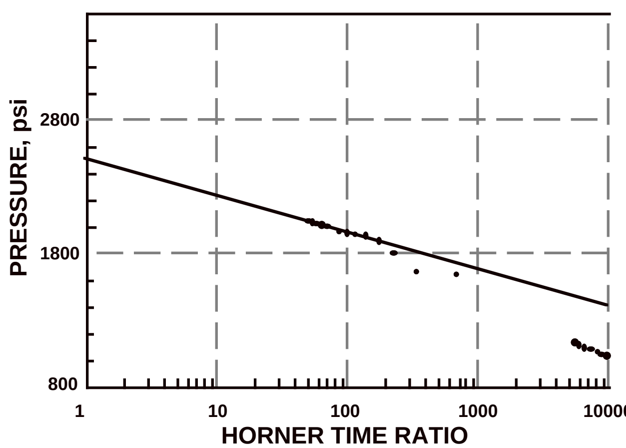

Fig. 10—Pressure Build-up Analysis Using Horner Plot- McGuire #1 Well

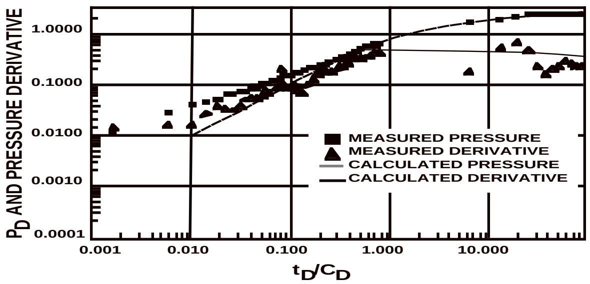

Fig. 11—Pressure Build-up Analysis Using Automatic Type Curve Matching- McGuire #1 well

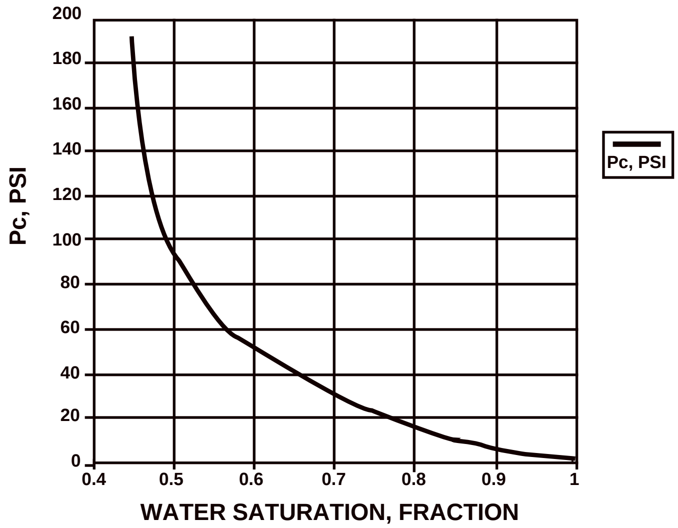

Fig. 13—Centrifuge Oil-brine Capillary Pressure - McGuire #2 Zone 3A @ 7332.2 Feet

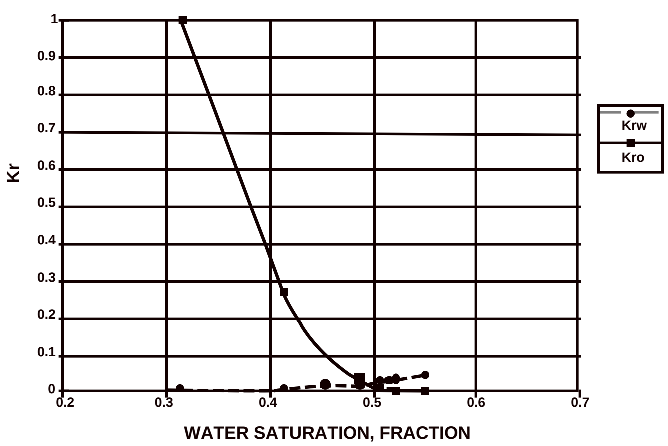

Fig. 12—Relative Permeability for Oil-brine System, McGuire #2 Zone 3A @ 7328.3 Feet

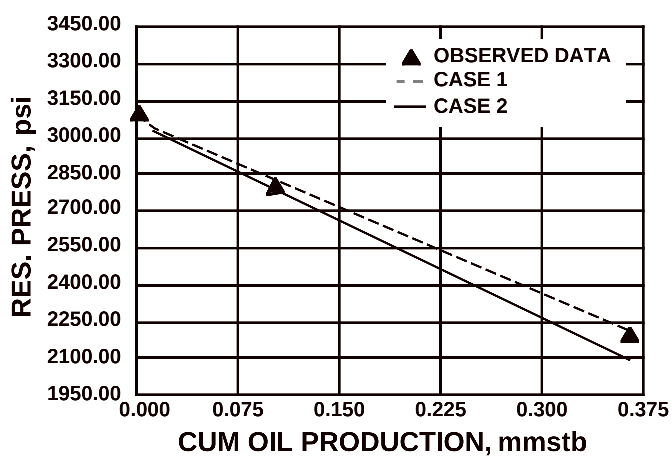

Fig. 14—Material Balance Pressure Match for East Randolph Field

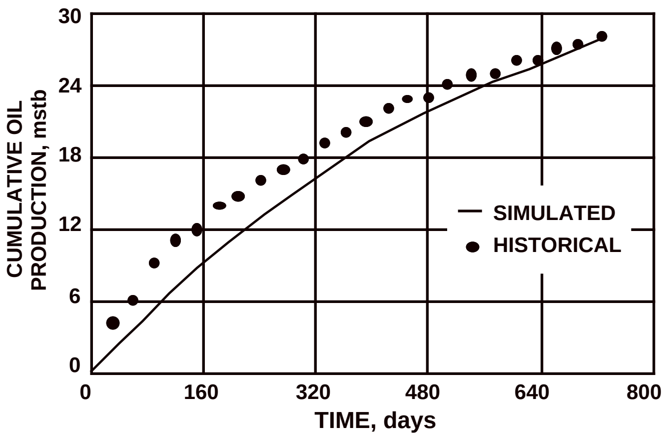

Fig. 15—History Match of Cumulative Oil Production for McGuire #1

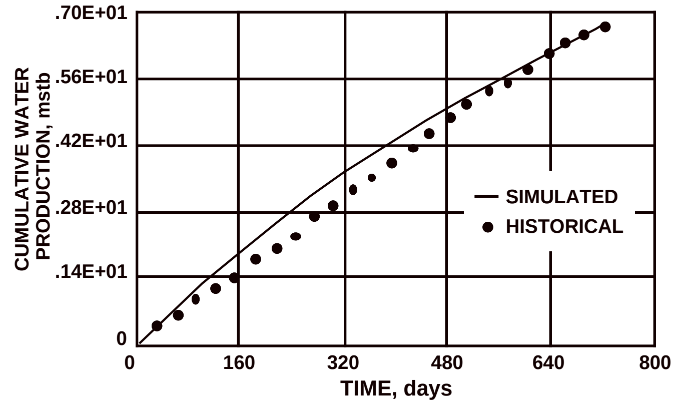

Fig. 17—History Match of Cumulative Water Production for McGuire #1

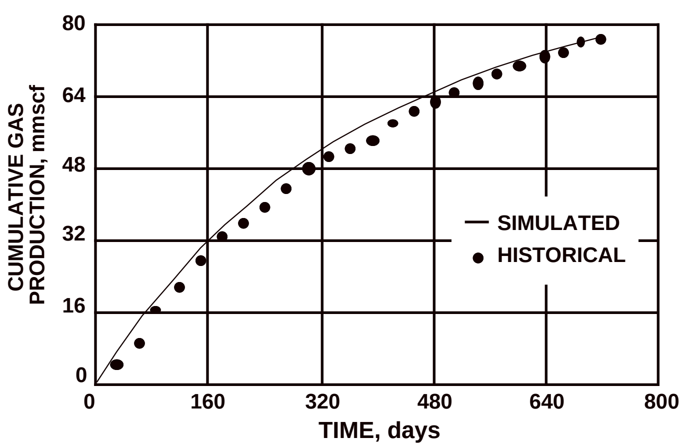

Fig. 16—History Match of Cumulative Gas Production for McGuire #1

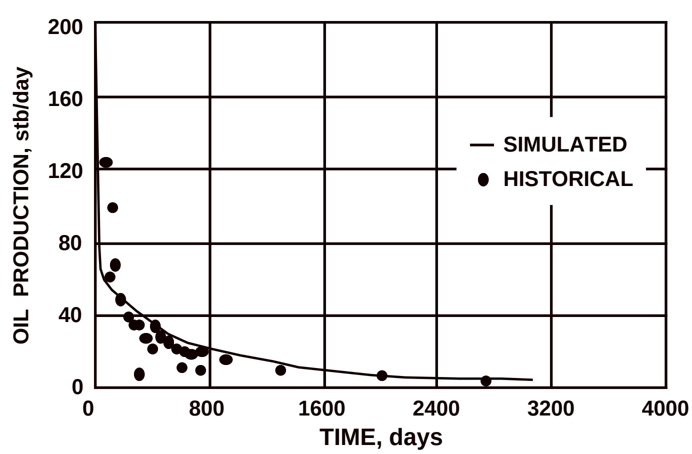

Fig. 18—Base Case Oil Rate Projection: History Match of Decline Curve Data vs. Simulated Data For McGuire #1

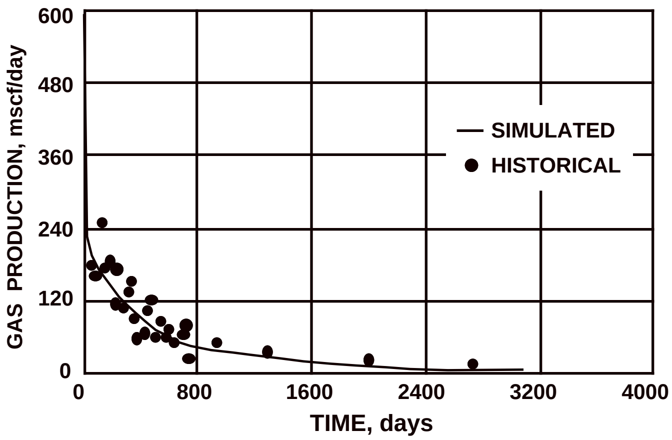

Fig. 19—Base Case Gas Rate Projection: History Match of Decline Curve Data vs. Simulated Data For McGuire #1

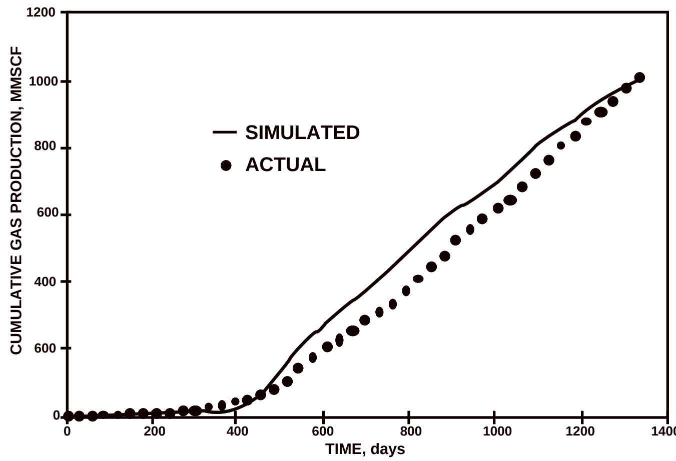

Fig. 21—Full-Field History Match of Cumulative Gas Production

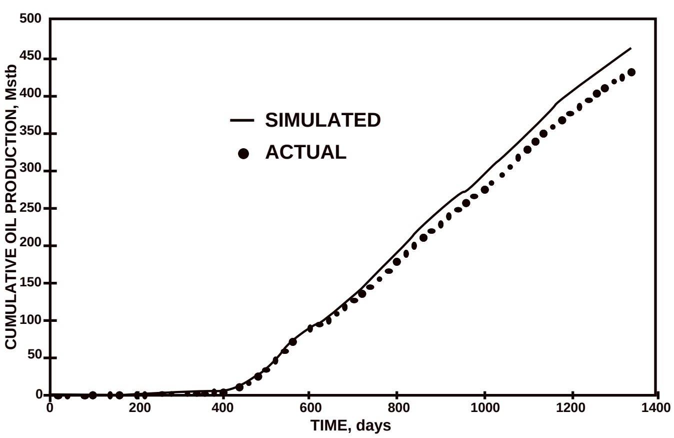

Fig. 20—Full-Field History Match of Cumulative Oil Production

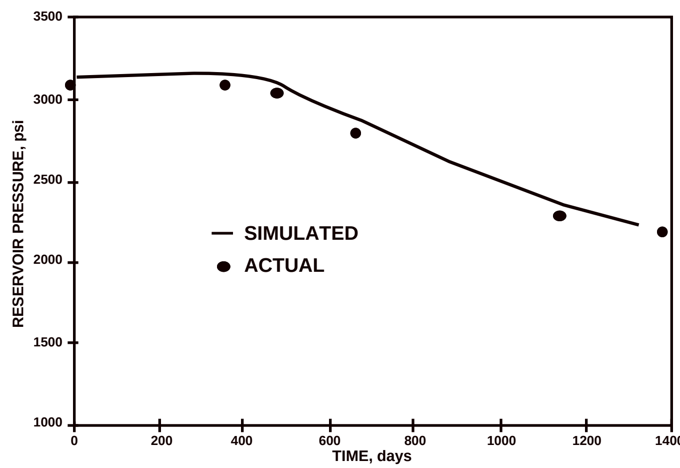

Fig. 22—Full-Field History Match of Reservoir Pressure